Title: **"Improved Miscible Nitrogen Flood Performance Utilizing Advanced Reservoir Characterization and Horizontal Laterals in a Class I Reservoir – East Binger (Marchand) Unit"**

Type of Report: **Topical Report - Budget Period 1**

Reporting Period Start: **April 11, 2000**

Reporting Period End: **March 31, 2002**

Principal Author/Investigator: **Joe Sinner**

Report Date: **March 26, 2002**

Cooperative Agreement No: **DE-FC26-00BC15121**

Contractor Name & Address: **Binger Operations, LLC**
P. O. Box 2850
Cody, Wyoming 82414

DOE Project Manager: **Gary Walker, National Petroleum Technology Office**

Disclaimer

"This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof."

"Improved Miscible Nitrogen Flood Performance Utilizing Advanced Reservoir Characterization and Horizontal Laterals in a Class I Reservoir – East Binger (Marchand) Unit"
DE-FC26-00BC15121

Topical Report for Budget Period I

Binger Operations, LLC
March 26, 2002

This topical report provides data associated with the title project, provided according to tables of information requested by the Department of Energy.

<u>Category/Table I – General Information</u>

Field Name	East Binger Field
Reservoir Name	Upper Marchand
State	Oklahoma
County	Caddo
Formation	Hoxbar
Field Discovery	Denver Production & Refining Company Adah-Noe No. 1 SW/4 Sec. 34-T10N-R10W January 1935
Current Operator	Binger Operations, L.L.C.

Current Working Interest Ownership (companies w/ > 10%):

Nielson & Associates, Inc.	52.3%
Canyon Oil & Gas Company	22.4%

Project Description:

<u>Background</u>: The Pennsylvanian Upper Marchand sand reservoir at East Binger Unit is located at a depth of 9,000 to 10,000 ft in the Anadarko Basin. OOIP for the Marchand sand unit of the Hoxbar group is 100 to 125 MMSTB. The Marchand reservoir covers 13,000 acres at East Binger Unit. 5,300 acres are on Indian lease lands. Phillips initiated flue gas injection in the 1970s, but had early gas break through. Over time the produced gas became unmarketable due to its increased nitrogen content. In 1986 a change was made to nitrogen injection, following the construction of a plant to extract nitrogen from

the produced gas and from the air. Nitrogen has the advantages of being widely available, cost-effective, and environmentally superior as an injectant for miscible floods. Binger Operations took over as the field operator in 1998 with 55 producers and 27 injectors. Cumulative production (Dec 2001) is 20.3 MMBO. Current production (Dec 2001) is approximately 810 bopd, with about 15 MMCFD N2 injection. The problems at East Binger are early injection breakthrough and cycling of injected nitrogen, resulting in a loss of miscible pressure. The project plans to demonstrate the effectiveness of horizontal wellbores in reducing gas breakthrough and cycling.

<u>Work to be Performed</u>: The objective of this project is two-fold. It will demonstrate use of nitrogen as a widely available, cost-effective and environmentally superior injectant for miscible floods. It will also demonstrate the effectiveness of horizontal wellbores in reducing gas breakthrough and cycling. It is expected that the demonstration will lead to implementation of nitrogen injection projects in areas without readily available carbon dioxide sources. Technology transfer will occur throughout the project.

Project Team Members:	Binger Operations, LLC** International Reservoir Technologies, Inc. ** Binger Operations, LLC is owned by Nielson & Associates, Inc. and Canyon Oil & Gas Company.
Technical Contacts:	Joe Sinner, Project Manager (307) 587-2445 1401 Sheridan Ave., Suite 205 Cody, WY 82414 Steve Slawson, Manager, Binger Operations, LLC (405) 232-0201 200 N. Harvey, Suite 1412 Oklahoma City, OK 73102

Primary Drive Mechanism: Solution Gas
Estimated Primary Recovery: 11%
Estimated incremental Secondary Recovery Factor: 14% (w/o this project)
Estimated Total of Primary and Secondary Recovery Factor: 25%

Date of first production:	January 1935
Number of wells drilled in Field:	133 (through 2001)
Well Patterns:	mixed 5-spot / line drive
Number of wells penetrating reservoir:	133
Total completions to date in field:	133
Total current completions:	87 (as of 12/31/2001)
Total current producers:	61 (as of 12/31/2001)

Total current injectors: 26 (as of 12/31/2001)
Number of flowing wells: 56

Summary field history:

The field was discovered in 1935, but after an offset dry hole was drilled, no other drilling took place until the 1970s. Three wells were drilled between 1972 and 1974, after which drilling activity accelerated and proceeded rapidly through 1975 and 1976. The field was developed on 160 acre drilling spacing units and prior to unitization in 1977, 95 wells had been drilled. Fourteen dry holes subsequently defined the productive area. The field produced approximately 3 million barrels of oil by primary production methods.

Initial potentials ranged upward to 1400 BOPD. The majority of wells exhibited an early decline rate of approximately 30% per year. A peak field oil production rate of 6,400 BOPD occurred during April 1976 when 61 wells were producing. Field-wide production may have continued to increase, but, in order to conserve reservoir energy, some operators voluntarily began restricting production from the initial allowable of 666 to 133 BOPD per well in April of 1975. In September 1975 after a hearing, the Oklahoma Corporation Commission (OCC) reduced the allowable to 133 BOPD. Through 1976, while unitization efforts were in progress, the OCC further restricted the allowable, first from 133 to 100 BOPD per well and later to 10 BOPD per well for most wells.

In January 1977, the operators reached a decision on an enhanced recovery method, inert gas injection, as well as the unitization parameters. On February 1, 1977, the legal allowable was raised by the OCC to 50 BOPD per well, where it remained until the effective date of unitization, August 1, 1977.

After unitization, thirteen production wells were initially converted to inert gas injection. Initial injection rates were 6 MMCFD, increasing to 20 MMCFD by 1979. By early 1978, however, the expected production response from inert gas injection had not yet materialized, and the field was experiencing areas of early gas breakthrough. Twenty-three infill development locations were drilled between 1980 and 1983. Ten infill wells drilled in 1981 resulted in 80-acre development in a portion of the field.

Early gas breakthrough, injectivity decline problems, and corrosion-related casing leaks were encountered during the first years of inert gas injection. The injectivity problems were dealt with by installing high efficiency coalescing filters at critical injection wells and at the plant, and implementing a variety of well clean-up treatments, including the use of xylene soaks and refracturing. Casing leaks were repaired with cement and/or liners. However, a number of wells were lost over time due to casing problems.

By the early to mid 1980s, increasing inert gas breakthrough volumes caused some of the produced gas to become unmarketable. Some wells, if they were appropriately located, were converted to gas injection. A secondary gas gathering system was also built to reinject unmarketable gas as a blend with the inert gas. The limits of this system were reached by 1985.

As the quantity of shut-in oil production increased, the re-injection of the high nitrogen gas became economically justifiable. In 1985, the Unit entered an agreement with Niject Services Company to provide nitrogen management services to the EBU. Niject designed, built and operated Nitrogen Management Facilities on-site to process the produced gas from the Unit, provide the Unit with high pressure, high purity nitrogen, and return to the Unit for sale the natural gas and natural gas liquids. The plant was came on line in December 1986. Niject owned and operated the plant through 1997. The Unit purchased the plant in January 1998, and took over operation of it in 2001.

<u>Category/Table II – 3-D Description of Reservoir</u>

<u>Areal and Vertical Description</u>

Areal Extent	13,000 acres (approx.)
Average Porosity	7%
Average Initial Oil Saturation	75%
Average Initial Water Saturation	25%
Average Initial Gas Saturation	0%
Average Permeability	0.15 md
Directional Permeability	0.08 md NW-SE, 0.22 md NE-SW
Pay Continuity	Very High
Reservoir Dip	1° to the SW
Faults	None known
Salt Domes	None
Average Net Pay Thickness	33’ (map included – Item 1)
Average Gross Pay Thickness	48’
No Gas Cap or Aquifer	

<u>Geologic Characteristics</u>

Lithology	Sandstone
Geologic Age	Pennsylvanian / Missourian

Additional information in Item 2 (listed in Attachment 1).

<u>Fluid Characteristics</u>

Initial Reservoir Pressure	5415 psia
Reservoir Temperature	190°F
Oil Gravity	45°API
Oil Viscosity at standard conditions	1.1 cp
Oil Viscosity at in-situ conditions	0.36 cp
Initial Oil Formation Volume Factor	1.52 RB/STB
Bubble Point Pressure	2786 psia
Initial Gas in Solution	1000 SCF/STB
Fluid Composition	See Item 3 (Appendix A of IRT Report)
Gas Gravity	0.85
Initial Gas Formation Volume Factor	N/A (no free gas)
Log of Bo, Rs, Bg vs. Pressure	See PVT reports
Water Density	Unknown
Water Viscosity	Unknown
Water Salinity	58,000 ppm assumed from nearby field

Category/Table III – Field Development History

Recovery Technique - Primary

Start Date	January 1935 (1st well) January 1972 (2nd well) 1975 (numerous wells)
Project Life	Ongoing
Estimated Incremental Recovery	11%
Timing of Drilling of New Wells	See "Well Cmpl&Stim Data.xls"
Monthly Production by well	See "Well Prod by Month.txt"
Number and Timing of new wells	See "Well Cmpl&Stim Data.xls"
Injection Data N/A	

Recovery Technique – Tertiary

Start Date	September 1, 1977
Type of Injectant	Flue Gas; then Nitrogen (December 1986)
Project Life	Ongoing
Estimated Incremental Recovery	14%
Monthly Production by well	Provided on Diskette
Monthly Production by well	See "Well Prod by Month.txt"
Monthly Injection by well	See "Well Inj by Month.txt"
Number and Timing of new wells	See "Well Cmpl&Stim Data.xls"
Number and Timing of conversions	See "Well Cmpl&Stim Data.xls"

Well Data

See "Well Cmpl&Stim Data.xls", "API-numbers.xls", and "LogData frPPCO.xls"

Category/Table IV – Field Production Constraints and Design Logic

Problem Statement – constraints on further producibility
(Excerpt from original grant proposal):

The EBU is currently undergoing enhanced recovery operations through the use of a miscible nitrogen flood. The main producibility problem within the miscible nitrogen flood at the EBU appears to be the early breakthrough and cycling of the injected gas, primarily through the higher permeability layers in the top section of the Marchand ‘C’ sand. These permeability variations are common reservoir heterogeneities found in Class I reservoirs. The reservoir heterogeneities are further complicated by the viscous fingering of the injected gas due to the unfavorable mobility ratio between the oil and the injected gas, and leads to the dissipation of the slug and poor sweep efficiency. Natural gravity segregation of the injected gas also plays a role in the producibility problem, when not properly managed, because the gas does not readily maintain a vertical moving miscible bank through the reservoir. Ultimately, this results in difficulties in achieving and maintaining miscible pressure throughout the reservoir and reduces expected ultimate recovery. It also results in unnecessary incremental operating expenses due to the additional processing and injection of the cycled breakthrough gas.

The producibility problems at the EBU have been apparent since early in the life of the EOR project, and have been partially responsible for a change in the injectant from flue gas to nitrogen. The miscible recovery process at the EBU was initiated at the time of unitization in August, 1977 with the injection of flue gas. Within one year, gas breakthrough was noted in various locations. As the channeling and breakthrough problems continued, they were initially handled by shutting in the offending wells, or by converting them to injection if properly located. Until 1986, the produced gas was sold directly to one of three pipelines, and the increasing nitrogen content reduced the BTU value of the gas, rendering it unmarketable.

In 1986, a Nitrogen Management Facility (NMF) was built in the Unit boundaries by Niject for the EBU. Its construction and use was intended to reduce the cost of inert gas production, address tubular corrosion and injector plugging problems attributable to products formed by the flue gas, and to improve the field economics by enabling oil production and recovery of NGLs from wells that had been shut-in due to gas breakthrough. The NMF is an integrated plant which combines cryogenic air separation, natural gas treating (sweetening), Natural Gas Liquid (NGL) processing, and cryogenic hydrocarbon gas separation and compression. Upon plant completion, the miscible process was converted over to the use of nitrogen as the inert injected gas.

The plant was originally designed to handle inlet gas with a nitrogen content of up to 70%. The NMF plant inlet gas composition is currently 71.76% nitrogen, with over a third of the active producers producing gas that is 70% or greater nitrogen. Several producing wells have been shut-in due to excessively high nitrogen content in the produced gas. The

NMF plant efficiency is currently limiting field production in that several wells with high gas-oil ratios (GOR's) have been restricted to allow the plant to operate with less down-time and within the original design envelope.

Reservoir characterization and simulation work has confirmed that high (relative to the majority of the reservoir) permeability channels exists within the reservoir, particularly along the top of the Marchand sand, that are enabling the channeling and cycling of injected gas through the reservoir. A review of the gas saturations across the reservoir suggests that gravity segregation effects are in-place and are exacerbating the gas-channeling problem. In addition, there are areas within the reservoir which are not receiving pressure support due to the cycling effects, and have fallen below miscibility pressure. All of these situations are working negatively against the ultimate recovery from this EOR process.

<u>Proposed Solution for Reduction of Constraints</u>
(Excerpt from original grant proposal):

Binger Operations intends, through this project, to demonstrate the potential to improve recovery by turning the natural fluid flow and reservoir properties to our advantage in improving sweep, maintenance of miscible pressure and ultimate recovery.

The project will incorporate the use of several advanced reservoir characterization and recovery technologies, and advanced reservoir management techniques. To further define the reservoir heterogeneities and extent of the producibility problems discussed above, this project will utilize a 3-D simulation in the form of a fine grid compositional window-area model encompassing the selected pilot area. The data for the window-area model will originate from the full-field model developed by IRT, and enhanced by additional pressure and reservoir property data, as well as flow profile information. The window-area model will also be used to aid in the planning of pattern development, the designing of the optimum configuration for the horizontal lateral sections, and injection facility needs.

The producibility problems will be addressed through the use of horizontal laterals placed in the lower portion of the sand section in producers, and along the upper portion of the reservoir in injectors. Completion and stimulation technology will be investigated to attempt to determine the most efficient manner in which to treat the horizontal sections without inducing fractures through which the gas could channel down into the wellbore. Fracture stimulation technology will also be investigated and incorporated into the stimulation of the injectors in the pilot area to optimize the volume of gas that is injected into this low permeability reservoir.

<u>Category/Table V – Evaluation of Cost-Share Project Results</u>

Type of Project	Advanced Tertiary (Miscible Gas w/ Horizontal Drilling)

<u>Injection Program</u>

Type of Injectant	Nitrogen (preceded by flue gas, 1977 – 1986)
Injection Schedule	See “Well Inj by Month.txt” (Category/Table 3)
Injection Pattern	mixed 5-spot / line drive

Number and Schedule of New Producers Drilled

EBU 37-3H	drilled 2Q 2001

Number and Schedule of New Producers Drilled
None to date

Number and Schedule of Conversions
None to date

<u>Simulation Study</u>

Type of Simulator Utilized	3-D full field compositional (VIP)
Simulator Input Data	Provided on CD
Simulation of Performance	Still in progress

<u>Project Economics</u>

Incremental non-drilling capital costs	
Plant Additions/Modifications	$ 330,000. (estimate)
Producer-to-Injector Conversions	$ 480,000. (estimate)

Drilling and Completion Costs by well	
EBU 37-3H	$ 3,900,000. (actual)
EBU 64-3H	$ 1,640,000. (estimate)
EBU 45-3H	$ 1,640,000. (estimate)
EBU 44-3H	$ 1,630,000. (estimate)
EBU 74G-2	$ 1,050,000. (estimate)

Reservoir Description Costs	
1 – Data gathering and processing	$ 170,000 (actual) + $ 270,000 (estimate)
2 – Reservoir simulation study	$ 80,000 (actual) + $ 140,000 (estimate)

Category/Table VI – Supporting Data

A list of materials is provided in Attachment 1.
Pressure data is provided in "EBU Pressure Table.xls"

Category/Table VII – Environmental Information

Surface Elevation	1300' – 1500' above SL
Surface Conditions	plains
Distance from navigable surface water	NA (> 5 miles)
Depth of groundwater	~ 200'
Volume of produced water	~ 10 b/d for entire field
Produced water disposal method	Haul to commercial disposal
Volume of drilling wastes from new wells	~ 15,000 bbls/well
Drilling mud content for new wells	LSND and oil base
Drilling mud handling practice	closed system on BIA land; lined pit on fee land
Surface impoundments	~ 20' x 80' lined cuttings pits (fee land only)
Results of recent M.I.T.s	copies among materials included

ATTACHMENT 1

Materials List for Topical Report for Budget Period 1

<u>Category/Table II - 3-D Description of Reservoir</u>

1 Map of Net Pay
2 East Binger Unit Reservoir Study, Phase 1, Final Report; Phillips Petroleum Company, December 1997
3 Appendix A from February 2000 International Reservoir Technologies Reservoir (Simulation) Study Report
4 PVT Report from Tin Noon A #1 (EBU 47G-1)
5 PVT Report from Bordwine A #1 (EBU 24G-1)

<u>Category/Table V - Evaluation of Cost-Share Project Results</u>

6 CD with simulator input data from International Reservoir Technologies

<u>Category/Table VI - Supporting Data</u>

7 8-1/2" x 11" copies of porosity logs from all wells in the field
8 EBU 37-3H mud log #1 (Horizon, 6,980' to 10,274')
9 EBU 37-3H mud log #2 (Horizon, 10,274' to 11,550')
10 EBU 37-3H GR log - Measured Depth (Baker Hughes INTEC)
11 EBU 37-3H GR log - True Vertical Depth (Baker Hughes INTEC)
12 EBU 37-3H Temperature log (Rosel, 7" Casing)
13 EBU 37-3H Acoustic Cement Bond Log (Arbuckle, 4-1/2" liner)
\- Net pay map - Item 1 above
\- Cross section - included in Item 2 above
\- PVT reports - Items 4 and 5 above
\- Core reports - data included in Item 2 above
14 EBU 37-3H Directional Survey
15 8-1/2" x 11" copies of well schematics from all wells in the field
16 EBU 37-3H Completion Reports
17 Wellwork histories for all wells in the field
\- Packed Column Displacement Study data included in Item 4 above
18 Solubility and Swelling Tests - Fluid Samples from EBU 79G-1
19 Phillips Internal Report JPJ-2-81 (March 16, 1981)
20 Phillips Internal Report JPJ-1-84 (August 22, 1984)
21 Phillips Report No. RL-395-R-9-75: Special Core Analysis Report (November 25, 1975)
22 Special Core Analysis Study on Ratliff No. 1 (EBU 44-1)

<u>Category/Table VII - Environmental Information</u>

23 Results of Recent Mechanical Integrity Tests

<u>Multiple Categories/Tables</u>

24 Floppy Disks containing monthly production and injection data, pressure data, API numbers, log data, and well completion and stimulation data